

**QUARTERLY INDEPENDENT MONITORING REPORT  
ON  
DUKE ENERGY CAROLINAS, LLC**

**Fourth Quarter 2010**

**Issued by:**

**Potomac Economics, Ltd.  
Independent Market Monitor**

**CONFIDENTIAL MATERIAL REDACTED**

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business activities). We also collect certain key data ourselves, including OASIS data and market pricing data.

The purpose of this report is to present the results of our monitoring activities and significant events on the Duke system<sup>1</sup> from October 2010 to December 2010.

#### A. Independent Monitoring

Potomac Economics performs the monitoring function on a regular basis, as well as performing periodic reviews and special investigations. Our primary monitoring is conducted by way of regular analysis of market data relating to transmission outages, congestion, and system access. This involves data on transmission outages, transmission reservation requests, Available Transfer Capability (“ATC”), transmission line loading relief (“TLR”) and curtailments or other actions taken by Duke to manage congestion. Analyses of this data aid in detecting congestion and whether market participants have full access to transmission service.

In addition to the regular monitoring of outages and reservations, we also remain alert to other significant events, such as price spikes, major generation outages, and extreme weather events that could adversely affect transmission system capability and give rise to the opportunity for anticompetitive conduct.

Our periodic review of market conditions and operations is based on data Duke provides, as well as other data that we routinely collect. Our review consists of four parts. First, we evaluate regional prices and transactions to provide an assessment of overall market conditions. Second, we summarize transmission congestion and the use of schedule curtailments in order to detect potential competitive problems. Congestion is identified by schedule curtailments<sup>2</sup> on Duke’s transmission system. Third, we evaluate the disposition of transmission service requests and TTC to analyze transmission access and

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<sup>1</sup> As allowed for in the monitoring plan, certain anomalous findings related to general market conditions, TTC, and transmission outages were shared with Duke to obtain clarification prior to submission to FERC and the state commissions.

<sup>2</sup> When we refer to schedule curtailments, we include TLR events because schedule curtailments are the main method used under the TLR procedures to manage congestion.

generation redispatch, transmission system reconfiguration, and schedule curtailments.<sup>3</sup> Of these, schedule curtailments have the most direct impact on market access and outcomes. Duke reserves and schedules transmission service primarily on a contract-path basis. A common situation in which Duke uses curtailments is when unscheduled firm reservation rights are released to the market and scheduled for non-firm use, but are then displaced when the higher-priority firm reservation holders subsequently submit schedules. The displaced non-firm schedules are curtailed. Curtailments can also occur when the paths reach their contract-path limits even though they may not be heavily loaded with physical flow. During the period of study, there were eight curtailments initiated by Duke and six TLR events in the region. All the TLR events were either initiated by PJM or TVA.

All curtailments regardless of their basis are important because they have the same impact on reducing transmission access. However, only schedules that are curtailed based on physical flow (including TLRs) are potentially influenced by Duke's operation of generation. We analyzed the impact of Duke's generation operations on the flow-based curtailments and do not find that Duke's dispatch of generation contributed to the events.

### 3. Transmission Access

We evaluate the patterns of transmission requests and their disposition to determine whether market participants have had difficulty accessing Duke's transmission network. If requests for transmission service are frequently denied unjustifiably, this may indicate an attempt to exercise market power. The volume of accepted requests was slightly lower than the previous quarter, and the approval rate was very high, averaging over 99.9 percent over the period of study. Given the high volume of service sold and the low level of refusals, we do not find a pattern in the disposition of transmission requests that indicates restrictive access to transmission.

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<sup>3</sup> We use the term schedule loosely in this context. It is actually e-tags that are curtailed. Each e-tag represents a physical sequence and time series of schedules. Therefore, one e-tag may have multiple schedules comprising it. Also, sometimes the same e-tag is curtailed more than once.

merit” dispatch) occurs and causes congestion, further analysis is warranted to determine whether the Company’s conduct raises competitive concerns.

Using an estimated supply curve, we analyze Duke’s actual dispatch to determine whether the actual dispatch departed significantly from what we estimate to be the economic dispatch. We then evaluate the contribution that the out-of-merit dispatch makes to flows on congested transmission paths to determine if congestion was either created and/or exploited by Duke. Our investigation into the congestion events found that generation dispatched out-of-merit order did not have a significant impact on curtailed paths. Consequently, we do not find evidence of anticompetitive conduct. Regardless, we did review the causes of the largest out-of-merit values even though they did not contribute to congestion events; we found that they were caused by justified generation forced outages and derates.

We also conducted an analysis of potential economic and physical withholding to further evaluate generation operations. Our measures of potential economic and physical withholding were not indicative of anticompetitive conduct. Evaluation of generation outage rates did not reveal evidence that generation outages were associated with anticompetitive conduct.

*Transmission Availability.* Finally, we evaluated Duke’s transmission outage events in order to determine whether these events may have unduly impacted market outcomes during the study period. We found no evidence of anticompetitive conduct.

## 5. Conclusions

Our analysis did not indicate any potential anticompetitive conduct from operation of the company’s transmission system or generation.

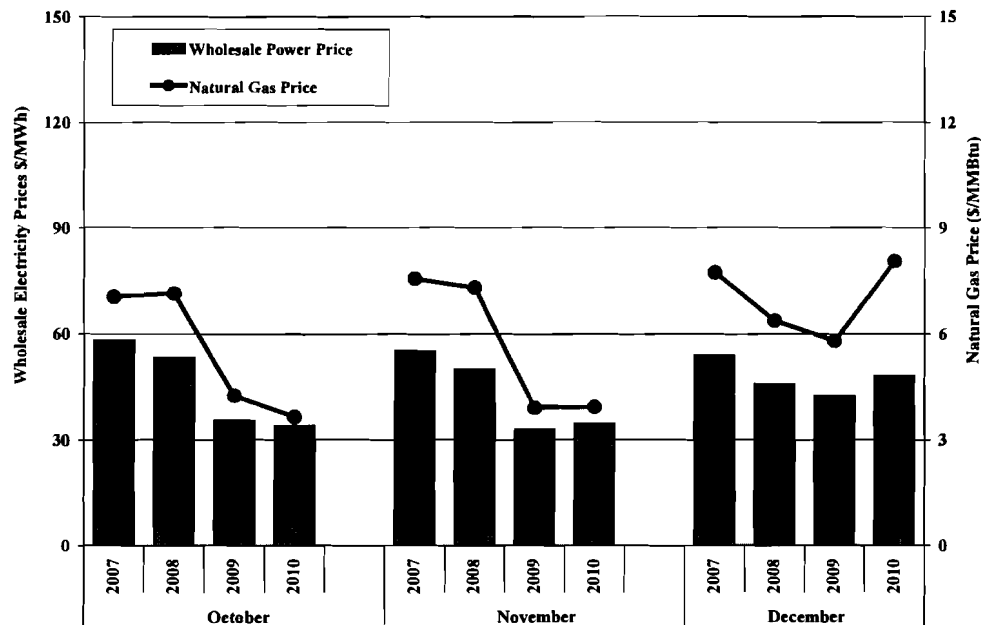
## C. Complaints and Special Investigations

We have not been contacted by the Commission or other entities regarding any special investigation into Duke’s market behavior, nor have we detected any conduct or market conditions that would warrant a special investigation.

We show system load data because of its expected correlation with power prices. We show natural gas cost because natural gas-fired units are most often the marginal unit supplying the grid, and because fuel costs comprise the vast portion of a generating unit's marginal costs. We use the daily price of natural gas deliveries by Transco at its Zone 5 location, a main pricing point for natural gas purchases by Duke. We translate this natural gas cost to a power cost assuming an 8,000 btu/kWh heat rate. This roughly corresponds to the fuel-cost portion of the operating cost of a natural gas combined cycle unit, which should generally correspond to the competitive price for power. Wholesale power prices ranged from \$31 per MWh to \$98 per MWh over the study period. As the figure shows, electricity prices spiked twice in the fourth quarter. This is explained by underlying spikes in natural gas prices and load.

The next analysis compares the average VACAR power prices for each month in the study period with the corresponding month of the previous three years. Results are shown in Figure 2 together with the average of the daily Transco Zone 5 natural gas prices. As the figure shows, electricity prices have generally been correlated with natural gas prices over time as one would expect.

**Figure 2: Trends in Monthly Electricity and Natural Gas Prices  
October 2007 – December 2010**



### III. TRANSMISSION CONGESTION

#### A. Overview

Duke is located in the SERC region of the North American Electric Reliability Council (“NERC”). NERC is certified as the Electric Reliability Organization (“ERO”) in the United States as of July 20, 2006. SERC is divided geographically into five sub-regions that are identified as Entergy, Gateway, Southern, TVA, and VACAR. VACAR is further divided into two intraregional coordination groups including VACAR North and VACAR South for the establishment of Reliability Coordinators (“RC”). Duke is within the VACAR South coordination group along with five other balancing authorities: Progress Energy Carolinas, Inc., South Carolina Electric & Gas Company, South Carolina Public Service Authority (Santee Cooper), Southeastern Power Administration, and Yadkin (a division of Alcoa Power Generation Inc).

Procedures to manage transmission congestion are implemented by the VACAR South Reliability Coordinator. The activities covered in these procedures include performing day-ahead and real-time reliability analysis, working with participants to correct System Operating Limit (“SOL”) and Interconnection Reliability Operating Limit (“IROL”) violations, and managing TLR events.

The VACAR South Reliability Coordinator utilizes an “Agent” to perform Reliability Coordination tasks. Duke, in addition to being a member of the VACAR South coordination group, is contracted to serve as Agent to perform the duties of Reliability Coordinator for itself and the other five VACAR South member companies. The transmission monitoring plan calls for monitoring Duke’s operation of its transmission system to identify anticompetitive conduct, including conduct associated with system operations and reliability coordination.<sup>5</sup> Our monitoring of such conduct is limited to conduct associated with Duke’s transmission system and does not extend to Duke’s activities as Agent for the VACAR South Reliability Coordinator.

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<sup>5</sup> See Transmission Service Monitoring Plan, Section 1.2.

not be at its physical limit. While contract-path-based curtailments have the same effects on market access as flow-based curtailments, these curtailments are not caused by the operation of generation.

Contract-path-based curtailments are implemented when transmission conditions reduce total transfer capability below the level of existing schedules on the contract path, which results in the curtailment of non-firm and possibly firm schedules. Contract-path-based curtailments are also the result of non-firm service being displaced to accommodate a schedule under a firm reservation. Since these conditions are not affected by generation operations, we only use the flow-based curtailments in our analysis of generation operations.

During the period of study, there were eight curtailments initiated by Duke, which were all contract-path based curtailments. There were six TLR events in the region. These events were either initiated by PJM or TVA.

Total volumes of approved requests during the period have slightly decreased from the same quarter last year and from the prior quarter. Although it is not obvious from the figure, the refusal volume was only 3.1 GWh during the fourth quarter of 2010, which is a decrease from the refusal volume of 9.8 GWh during the same quarter last year and a decrease from the refusal volume of 14 GWh during the third quarter of 2010. The approval rate of transmission service requests was very high over the study period, averaging over 99.9 percent. Given the high volume of approved requests and the low volume of refused requests, we do not find evidence that Duke has restricted access to transmission capability.

To evaluate the disposition of transmission requests further, we compare the volume of transmission requests over the study period by increment of service to the requests from the corresponding period a year prior. This comparison is shown in Figure 5.

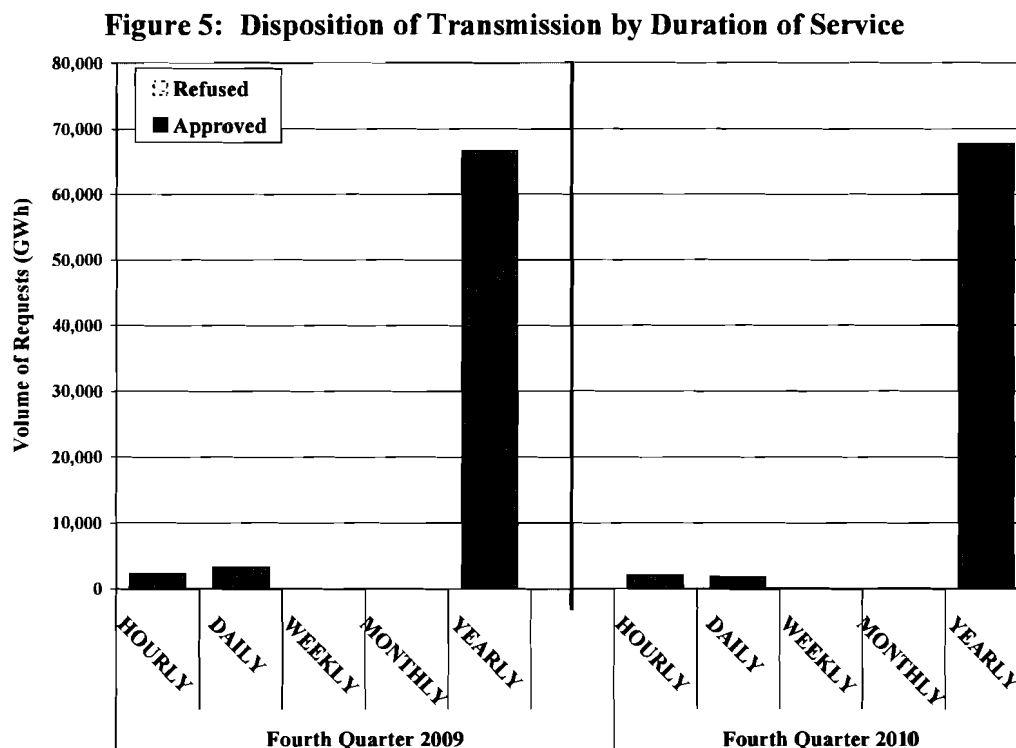
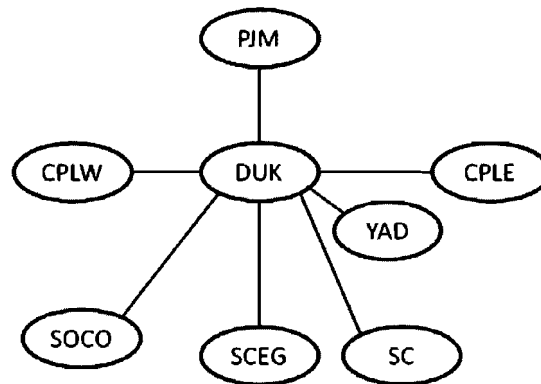


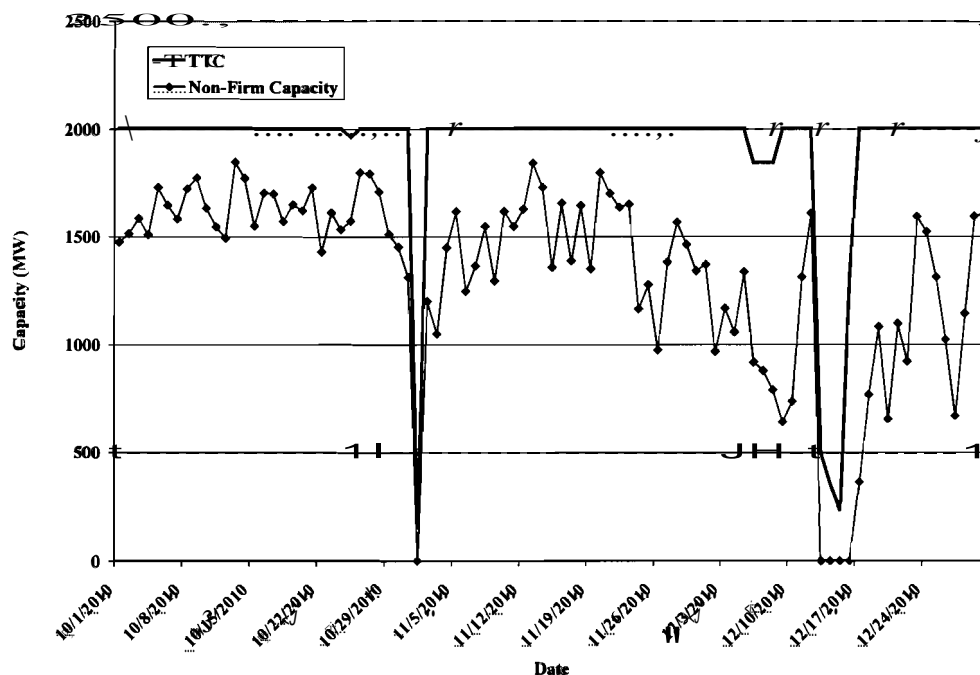
Figure 5 indicates small increases in the approvals of yearly, weekly and monthly services and decreases in the approvals of the hourly and daily services. This shows a slight overall decrease in approvals with a shift to yearly service. The volume of refusals is less than what it was in the same period of the prior year. The refusals are too small to be visible in the figure. These increases in approval volumes for yearly service further support the conclusion that transmission

Figure 6: Key Paths

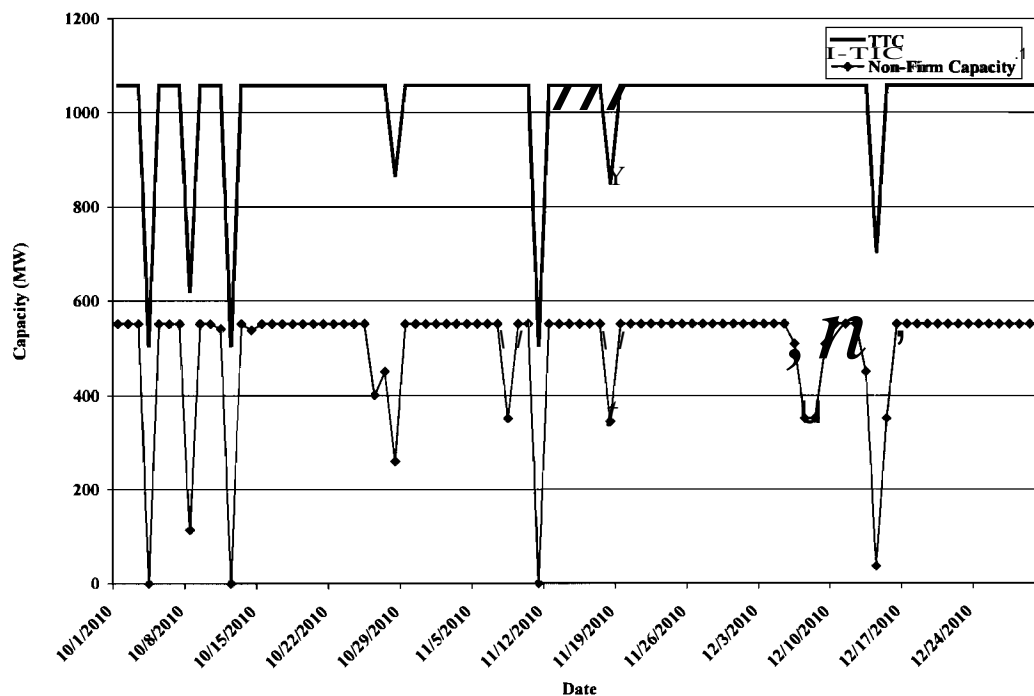


Of the key paths, the segments of “Duke to PJM”, “Duke to SOCO”, “Duke to SC”, “Duke to SCEG”, “SC to Duke” and “PJM to Duke” had instances of near zero Non-Firm ATC coincident with TTC reductions. These path segments are candidates for further review because days when the non-firm ATC was at or near zero coincident with a reduction in TTC may represent Duke improperly reducing TTC in order to reduce competitors’ access. The minimum TTC and non-firm ATC for each day for these path segments are shown in Figure 7 through Figure 12 below.

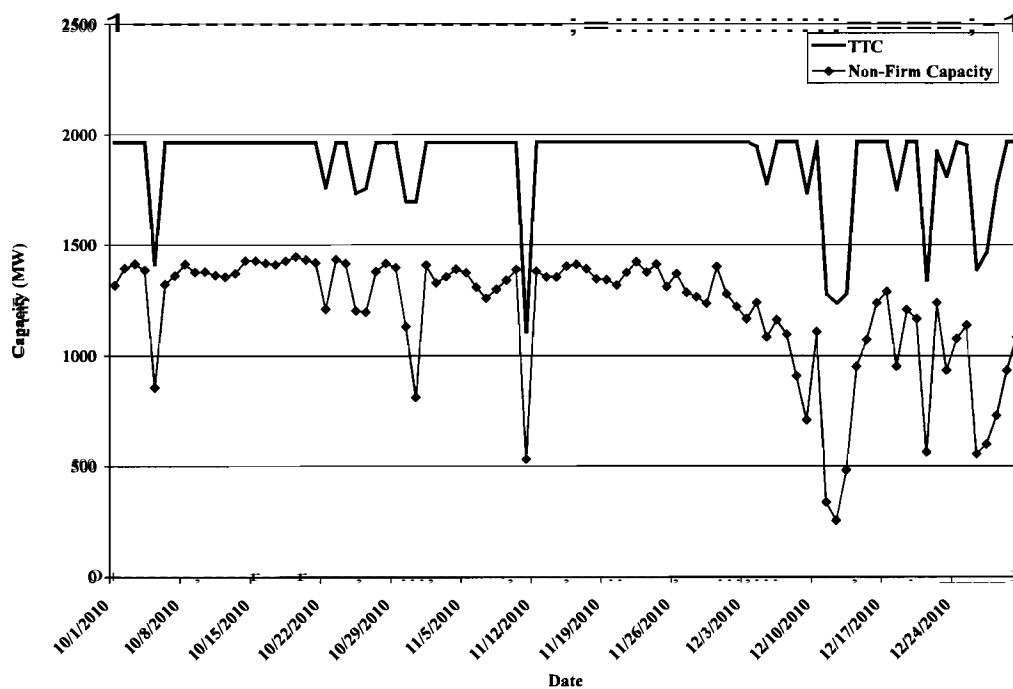
**Figure 7: DUK to PJM Daily Minimum of Hourly Capacity  
October 2010 – December 2010**



**Figure 10: DUK to SCEG Daily Minimum of Hourly Capacity  
October 2010 – December 2010**



**Figure 11: SC to DUK Daily Minimum of Hourly Capacity  
October 2010 – December 2010**



there were either TSR refusals or schedule curtailments associated with the TTC reductions. It is on these days that competition may be affected.

- *October 12, Duke to SCEG:* Non-firm schedules were curtailed on the “PJM to SCEG” path due to a TTC reduction caused by a constraint on the “Duke to SCEG” segment. [REDACTED]  
[REDACTED] Though the modeled constraint limited the TTC to zero (actually an overload of -534 MW), Duke only reduced the TTC to 506 MW, which was the level of the Transmission Reliability Margin (TRM) plus firm transmission rights. The purpose of this was to avoid the curtailment of firm schedules unless needed in the real-time.
- *December 12, SC to Duke:* Non-firm schedules were curtailed on the “SC to Duke” path due to a TTC reduction caused by the constraint [REDACTED]  
[REDACTED] The constraint limited the TTC to 1,235 MW.
- *December 13, Duke to SOCO:* TSRs were refused on the “PJM to SOCO” path which was constrained by “Duke to SOCO” segment. The segment was limited by the constraint [REDACTED] The constraint limited the TTC to 1,064 MW.
- *December 14, Duke to SOCO:* TSRs were refused on the “PJM to SOCO” path which was constrained by “Duke to SOCO” segment. Also, non-firm schedules were curtailed on the “Duke to SOCO” path. The TTC was limited by the constraint [REDACTED]  
[REDACTED] Though the modeled constraint limited the TTC to 237 MW, Duke only reduced the TTC to 428 MW, which was the level of the Transmission Reliability Margin (TRM) plus firm transmission rights. The purpose of this was to avoid the curtailment of firm schedules unless needed in the real-time.
- *December 14, Duke to PJM:* TSRs were refused and non-firm schedules were curtailed on the “Duke to PJM” path. The TTC was limited by the constraint [REDACTED]  
[REDACTED] The constraint limited the TTC to 353 MW.
- *December 15, Duke to SOCO:* TSRs were refused on the “PJM to SOCO” path which was constrained by the “Duke to SOCO” segment. Meanwhile, schedules were curtailed on

## V. MONITORING FOR ANTICOMPETITIVE CONDUCT

In this section, we report on our monitoring for anticompetitive conduct. The market monitoring plan calls for identifying anticompetitive conduct, which includes conduct associated with the operation of either Duke's transmission assets or its generation assets that can create transmission congestion or erect barriers to rival suppliers, thereby raising electricity prices. To identify potential concerns, we analyze Duke's wholesale sales in the first subsection below, its dispatch of generation assets in the second subsection, and Duke's transmission operations in the third subsection.

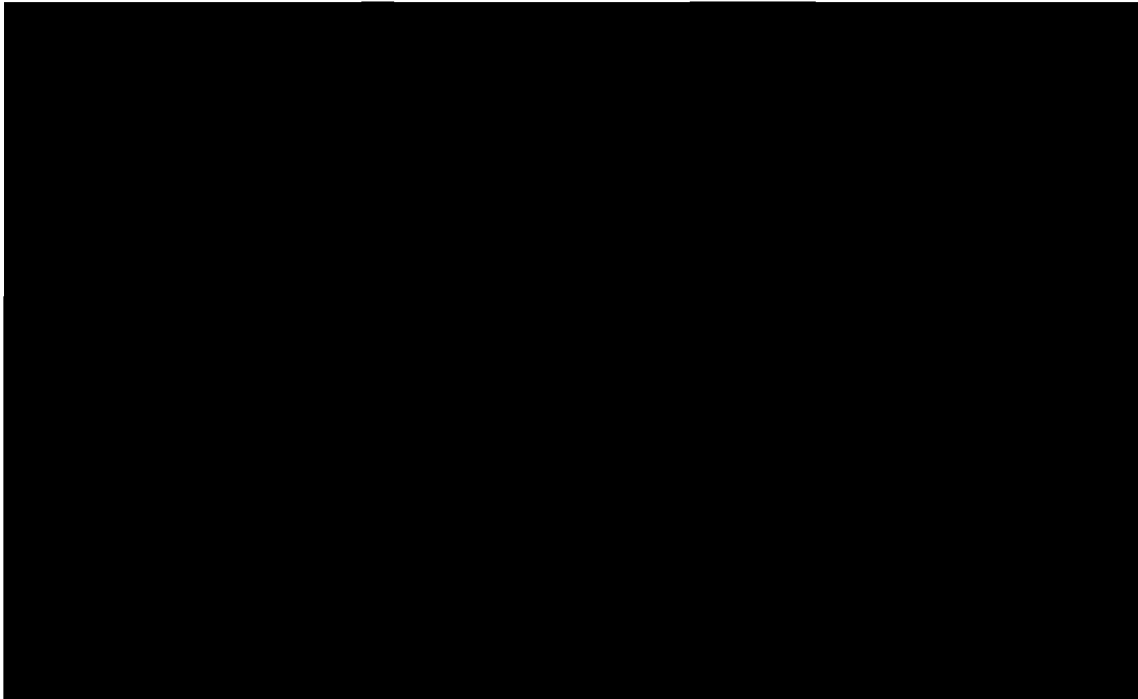
### A. Wholesale Sales and Purchases

We examine transaction data to determine whether the prices at which Duke sold or purchased power may raise concerns regarding anticompetitive conduct that would warrant further investigation. We are particularly interested in periods when transmission congestion arises. If Duke were engaging in anticompetitive conduct to create congestion, it could potentially benefit by making sales at higher prices in constrained areas or purchases at lower prices adjacent to constrained areas. We examined the real-time bilateral transactions made by Duke using Duke internal records. We focus on real-time transactions because anticompetitive conduct is likely to be more successful in the real-time market.

Competition is facilitated by the ability of rivals to gain market access by reserving and scheduling transmission service. Access will be limited if ATC is unavailable, transmission requests are refused, or schedules are curtailed. Curtailments are also an indicator of congestion because they can be made when a path is over-scheduled or physically overloaded. If Duke's ability to curtail schedules is being abused, we would expect to see systematically higher prices for sales or lower prices for purchases coincident with curtailments.

Recall that curtailments can be flow-based (i.e., the result of flows exceeding the system operating limit), or contract-path-based (i.e., the result of contract-path reservations exceeding the path rating). For our analysis of Duke's sales, we use both types of curtailments. This is reasonable because both types of curtailments reduce market access. Moreover, Duke has the direct ability to affect both flow-based curtailments and contract-

**Figure 13: Prices for Duke Sales and Purchases  
October 2010 – December 2010**



The weighted average daily prices of Duke's sales range between \$[REDACTED] per MWh and \$[REDACTED] per MWh. The volume-weighted average daily sales price was \$[REDACTED] per MWh. On days with curtailments that may have benefited Duke's net sales position, the average sales price was \$[REDACTED] per MWh. The weighted average daily prices of Duke's purchases range between \$[REDACTED] per MWh and \$[REDACTED] per MWh. The volume-weighted average daily purchase price was \$[REDACTED] per MWh. On days with potentially beneficial curtailments, the average purchase price was \$[REDACTED] per MWh. The transaction prices when the system was congested were not more favorable than average prices over the period of study. Thus, the transaction prices in general do not raise competitive concerns, but we look further into days with positive Max Effect.

On October 25, [REDACTED] At the same time, a TLR was declared on flowgate 310.<sup>12</sup> The sales prices were low when compared to other

<sup>12</sup> Flowgate 310 is defined as "Person to Halifax 230 kV line for the loss of the Wake to Carson 500 kV line".

### 1. Out-of-Merit Dispatch and Curtailments

Congestion can be a result of limits on the transmission network when utilities dispatch their units in a least-cost manner. This kind of congestion does not raise competitive concerns. If a departure from least-cost dispatch (“out-of-merit” dispatch) is unjustifiable and causes congestion, it raises potential competitive concerns.

We pursue this question by measuring the out-of-merit dispatch on the Duke system. In our analysis, we consider a unit to be out-of-merit when it is dispatched when a lower-cost unit is not fully loaded at the same time. To identify out-of-merit dispatch, we first estimate Duke’s marginal cost curve or “supply curve”.<sup>13</sup> We use incremental heat rate curves, fuel cost, and other variable operations and maintenance cost data provided by Duke to estimate marginal costs. This allows us to calculate marginal costs for Duke’s units. We order the marginal cost segments for each of the units from lowest cost to highest cost to represent the cost of meeting various levels of demand in a least-cost manner. For our analysis, the curve is re-calculated daily to account for fuel price changes, planned maintenance outages, and planned deratings.

Figure 14 shows the estimated supply curve for a representative day during the time period studied.

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<sup>13</sup> We use the term marginal cost loosely in this context. The value we calculate is actually the *marginal running cost* and does not include opportunity costs, which may include factors such as outage risks or lost sales in other markets.

parameters (i.e., start costs, run-time and down-time constraints, etc.), we believe this simplified incremental-operating-cost approach is adequate to detect instances of significant out-of-merit dispatch that would have a material effect on the market.

When a unit with relatively-low running costs is justifiably not committed, our least-cost dispatch will overstate the out-of-merit quantities because it will identify the more expensive unit being dispatched in its place as out-of-merit. This may result in higher levels of out-of-merit dispatch during low-load periods when it is not economic to commit certain units.

Other justifiable operating factors that cause the out-of-merit dispatch to be overstated are energy limitations and ancillary services. An example of an energy limitation is a coal delivery problem that prevents a coal plant from being fully utilized. Because the coal plant is still capable of operating at full load for a shorter time period, the condition does not result in a planned outage or derating. The necessity to operate the plant at reduced load to conserve coal can cause the out-of-merit values to be overstated.

Ancillary services requirements such as spinning reserves, system ramp rate limitations, and AGC control requirements can make it operationally necessary to dispatch a number of units at part load rather than having the least expensive unit fully-loaded. These operational requirements can cause the out-of-merit values to be overstated. The out-of-merit quantities include units on unplanned outage since a sudden unplanned outage may be an attempt to uneconomically withhold generation from the market.

Overall, our analysis will tend to overstate the quantity of generation that is truly out-of-merit. Accordingly, the accuracy of a single instance of out-of-merit dispatch is not as important as the trend or any substantial departures from the typical levels.

In our analysis, we seek to identify days with significant out-of-merit dispatch that coincides with transmission congestion. Congestion is indicated by flow-based schedule curtailments. Flow-based curtailments are those that are taken close to real-time in order to prevent physical flows from exceeding system operating limits. Out-of-merit dispatch can be used to affect these flows and create the need for curtailments, potentially limiting

There is no evidence of anticompetitive conduct because the outage is justified and did not contribute to curtailments.

## 2. Output Gap

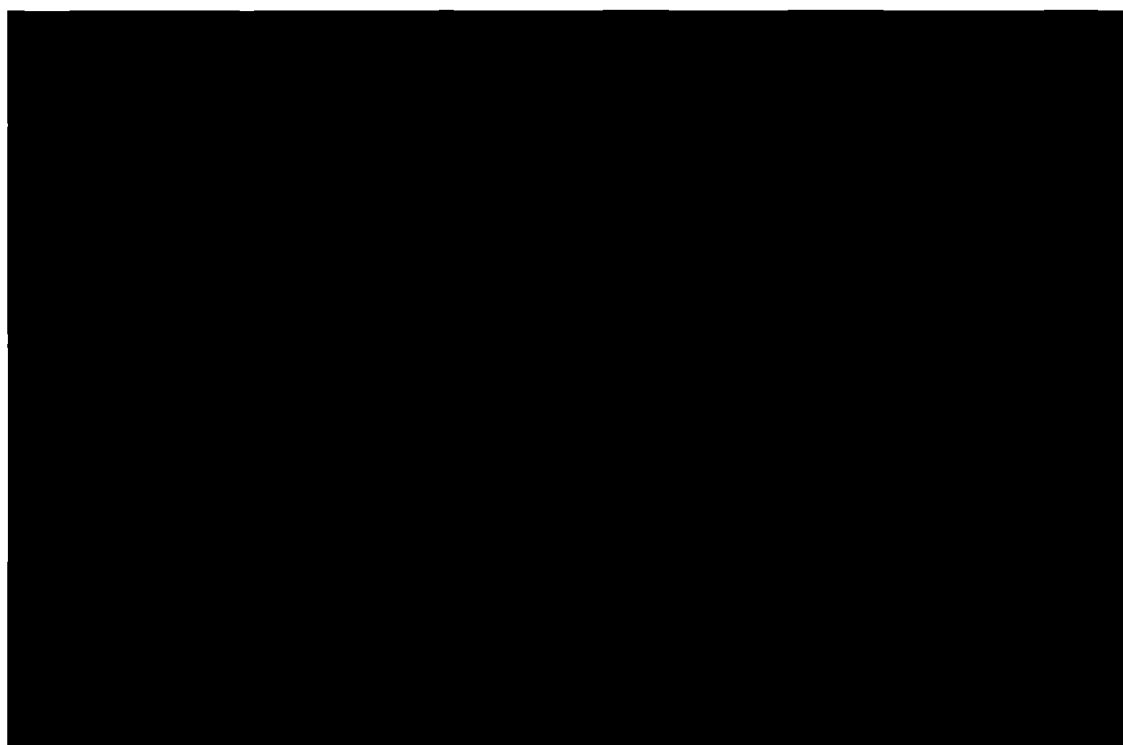
The output gap is another metric we use to evaluate Duke's generation dispatch. The output gap is the unloaded economic capacity of an available generation resource. The capacity is economic when the prevailing market price exceeds the marginal cost of producing from that unit by more than a specified threshold. We use \$25 per MWh and \$50 per MWh as two thresholds in our analysis. Hence, at the \$25 per MWh threshold, if the prevailing market price is \$60 per MWh and a unit with marginal costs of \$40 per MWh is unloaded, then we do not consider this part of the output gap because the marginal cost plus the \$25 per MWh threshold is greater than the \$60 per MWh market price. However if the marginal cost is \$30 per MWh, we would consider it in the output gap at the \$25 per MWh threshold, but not under the \$50 per MWh threshold. This quarter, there were four output gap events for at least one threshold as shown in Figure 16.

We analyze the market for the 16-hour daily on-peak power product, because this is the most liquid market in the VACAR South region and it is where market power would be the most profitable. We also analyze the 16-hour on-peak average of the hourly PJM real-time market prices, because it is the most liquid real-time market in the region. We compare these prices to the marginal cost of each generator. The daily output gap for each generator is expressed as the output gap for the hour when the generator reaches its peak output level for the day. The results are the sum of the daily output gap of the included generation. Only units that are committed during the day are included in the daily calculation. Hydro and nuclear units are also excluded because nuclear resources rarely change output levels in response to market conditions for a variety of reasons and the opportunity costs associated with hydroelectric resources make it difficult to accurately estimate their costs.

### 3. Generator Availability

We evaluate generator availability by examining the amount of capacity on outage as well as the ratio of capacity on outage to total capacity. Our first analysis is in Figure 17. We compare the daily average capacity on outage during the on-peak hours as well as the VACAR price and the prices at which Duke made real-time sales.

**Figure 17: Outage Quantities  
October 2010 – December 2010**



The figure shows that Duke sales prices are typically above the VACAR market index price. Some differences are expected because the Duke sales prices reflect real-time transactions while the wholesale prices reflect day-ahead transactions. Our main interest is in unplanned generation outages that cause increases in market prices. The figure shows that on November 16 there were high outage volumes that were coincident with significant spikes in Duke's sales prices. We requested additional information on the individual unplanned unit outages and found the following:

- [REDACTED]
- [REDACTED]  
[REDACTED]

**Figure 19: Correlation of Average Outage Rates with Wholesale Energy Prices  
October 2010 – December 2010**

	Correlation with VACAR Index	Correlation with Duke Real-Time Sales Prices
Planned Outages	-47%	-28%
Unplanned Outages	2%	17%

Figure 19 reports both planned and unplanned outages. The unplanned ones are the most important from a market power perspective. Planned outages are expected and generally are scheduled in off-peak periods. Unplanned outages can occur during peak times. The negative correlations of the planned outage rate with VACAR index price and Duke real-time sales prices are expected given that planned outages are typically scheduled during off-peak periods when prices are lower. The correlations of the unplanned outage rate with Duke real-time prices and the VACAR index are positive. This is driven by the generation outages described above. The outages are found to be justified even though they may have contributed to high Duke sales prices. Based on the correlation with the VACAR index, the impact from unplanned outages is relatively small and does not raise concern.

Based on the results, we find no evidence that generation outages were associated with anticompetitive conduct.

#### C. Analysis of Transmission Availability

Transmission outages are reviewed in order to determine whether they limit market access and, if so, whether they are justified. There were 66 transmission outages that affected power flows on elements at 100 kV and higher during the period of study. We reviewed these outages with a focus on conditions that would have reduced transfer capability on the key paths when the TTC was reduced and the ATC was near zero as shown in Figure 7 through Figure 12. Based on our review of the shift factors of the equipment in outage to the limiting contingencies for setting TTCs, we found the following outages to be of interest.

- [REDACTED] This four-day planned maintenance outage was taken by AEP on November 1, 2010. [REDACTED]  
[REDACTED]